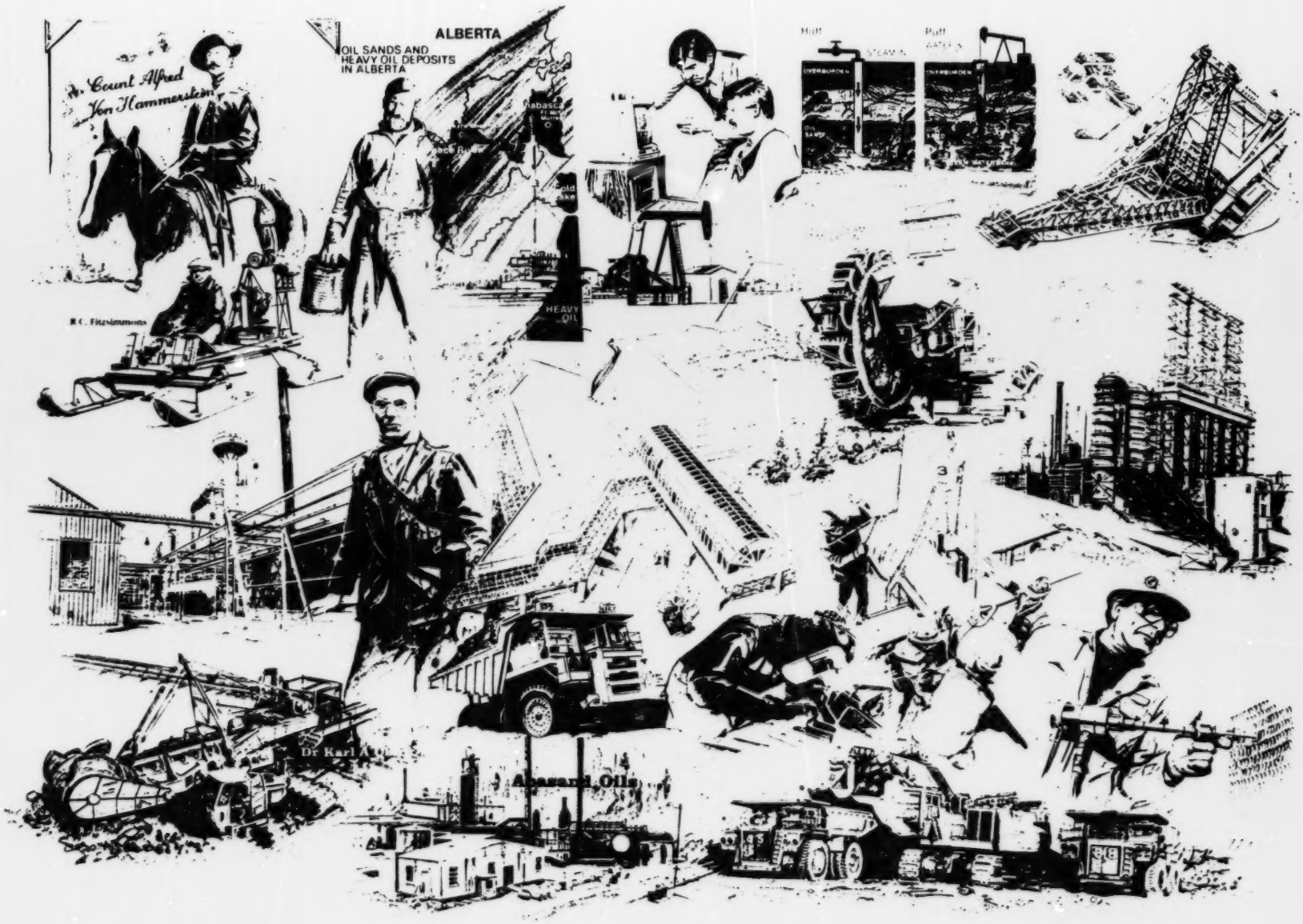
ALBERTA
OIL SANDS AND
HEAVY OIL DEPOSITS
IN ALBERTA
Count Alfred
Von Hammerstein
HEAVY
OIL
Dr Karl
Abasand Oils

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Commissioned by Alberta Culture and Multiculturalism, *History of Oil Sands* commemorates the opening of the Fort McMurray Oil Sands Interpretive Centre.

Alberta PETROLEUM MARKETING COMMISSION

1900, 250 Sixth Avenue S.W., Calgary, Alberta, Canada T2P 3H7 Telex 03-821978 (403) 297-5500

July 31, 1987

The Honourable Dr. Neil Webber
Minister of Energy
Government of Alberta
Legislature Building
Edmonton, Alberta
T5K 2B6

Dear Sir:

In accordance with the provisions of the Petroleum Marketing Act, the Natural Gas Pricing Agreement Act and the Take-or-pay Costs Sharing Act, the Alberta Petroleum Marketing Commission has prepared a general report summarizing its transactions and affairs for the fiscal year ended December 31, 1986. I have the pleasure to submit the 1986 Annual Report that you may lay a copy before the Legislative Assembly

Respectfully,

D. A. Lucas
Chairman

Foreword

During the year, the sharp reduction in crude oil prices, precipitated at the year's onset by OPEC's efforts to regain markets in a world surplus situation, challenged the abilities of Alberta's crude oil marketers, including the Commission. In response, the Commission developed new marketing strategies which included sales into non-traditional markets, thereby reducing the extent of shut-in production.

Natural gas prices in Canada and the United States also came under pressure from lower demand and excess supply in both countries, from competition from alternative fuels, including lower priced fuel oil, and from gas-to-gas competition. This presented a difficult environment in which to move forward with the transition to market pricing for natural gas within Canada under the terms of the October 31, 1985 Agreement on Natural Gas Markets and Prices (Agreement). Although significant progress was achieved in the move from regulated natural gas pricing to a more flexible, market-oriented pricing system within Canada, it is obvious that several additional issues have arisen requiring resolution by governments and industry.

In addition to the challenges associated with marketing crude oil, the year brought significant changes to the Commission's responsibilities and functions related to natural gas marketing as a result of the implementation of the Agreement. It also brought a heightened level of activity in regulatory proceedings, especially in matters pertaining to the terms and conditions under which Alberta's natural gas production is transported and marketed beyond the province's borders.

Market Background

Petroleum Markets

A dramatic decline in world oil prices dominated international energy markets during the year. The decline was precipitated by a drive begun late in 1985 by the members of OPEC, Saudi Arabia in particular, for a greater share of world oil markets. Between 1979 and 1985, OPEC's world market share (excluding the centrally planned economies) fell from approximately 60 percent to less than 40 percent. Over the same period, Saudi Arabia's share of OPEC production declined from approximately 30 percent to 20 percent.

The success of OPEC's efforts to improve its market share was neither as large nor as immediate as many of its members had wished. Moreover, the effect on prices was catastrophic as they decreased over 50 percent in six months. In the latter part of 1986, Saudi Arabia abandoned netback pricing which it had adopted as a means of regaining market share in favour of a return to official prices. At its December 1986 meeting, OPEC agreed to set fixed prices and lower production quotas, effective February 1987.

These lower prices for crude oil stimulated demand in the United States to 2.6 million cubic metres per day (16.1 million barrels per day), a 2.6 percent increase over 1985. Gasoline consumption gained strongly as lower prices encouraged travel. Residual fuel oil captured markets from higher priced natural gas in the electric utility and industrial sectors. At the same time, U.S. crude oil production fell by 2.5 percent to 1.7 million cubic metres per day (10.5 million barrels per day), mainly as a result of the shutting in of uneconomic production from stripper wells and sharp reductions in drilling activity. Because of this growth in demand for petroleum products and the decline in domestic production, U.S. crude oil imports increased by 159 000 cubic metres per day (1 million barrels per day). Canada shared in supplying these increased requirements as total exports to the United States and offshore increased 25 percent to average 93 000 cubic metres per day (585,000 barrels per day).

The collapse of world oil prices also had the effect of making imported oil more attractive to Canadian refiners in those markets with access to imported supplies and at some distance from western Canada. In Montreal, for example, the market share of imported crude oil increased from an average of 30 percent in 1985 to over 50 percent by the end of 1986. In Canada as a whole, imports rose to 26 percent of the market in 1986 from 20 percent in 1985.

Unlike the United States, however, demand for crude oil in Canada during this same period declined, reflecting a two percent decline in overall demand for refined petroleum products. Although there was some growth in product demand in Ontario, prompted by a strong local economy, it was more than offset by declines in all other Canadian regions. Net exports of refined petroleum products fell in all regions but Atlantic Canada where a strong products market in the northeastern United States gave refiners the opportunity to process crude oil runs almost exclusively for export. The result, when combined with increased imports, was a nine percent decline in requirements for domestic oil by Canadian refiners. Deliverability constraints caused by limited pipeline capacity hampered Alberta crude oil production. On average, just under 12 500 cubic metres per day (79,000 barrels per day) were shut in. The productive capacity of Alberta crude oil also declined. In the fourth quarter, producibility was just under three percent less than in the same period one year earlier. Slight increases in the productive capacity of heavier crudes, however, helped to mitigate the declines in light and medium crude oil productivity.

Production of Alberta crude oil declined 2 000 cubic metres per day (12,500 barrels per day) from 1985 levels to an average 205 000 cubic metres per day (1.29 million barrels per day). Total Canadian production of 249 000 cubic metres per day (1.57 million barrels per day) represented a marginal decline from the previous year.

Natural Gas Markets

The on-going process of deregulation and large surpluses characterized natural gas markets in both Canada and the United States. Natural gas buyers and sellers were required to adapt quickly to changing markets, a process which was complicated by actions taken by United States regulatory authorities to promote greater competition through the dismantling of the traditional transportation and supply roles of pipelines.

In the United States, total demand for natural gas declined from 1985 levels as a result of warm winter weather, competition from alternative fuels, poor industrial performance and increased energy efficiency. In addition, the United States "gas bubble" and regulatory initiatives promoted the growth of spot and short-term markets, which some industry observers estimated represented one-half of all natural gas sales by year-end.

These two factors, compounded by impediments to pipeline access, made it difficult for Alberta natural gas to compete in the United States market. Canadian natural gas exports declined steadily, falling 21 per cent from the previous years. Stiff price competition resulting from the sharp decline in world oil prices and surplus supplies also had a dampening effect on prices. Reductions in negotiated contract prices were required to maintain export sales.

Efforts to remove impediments to export sales also continued in keeping with the objectives of the October 31, 1985 Agreement on Natural Gas Markets and Prices (Agreement) signed by the governments of Canada, British Columbia, Alberta and Saskatchewan. The adjacent-zone border price test, applied by the National Energy Board (NEB) since October 1985 to ensure that export prices are not less than those charged to Canadians for similar service in the area adjacent to the export point, was replaced by more flexible, post facto monitoring to be undertaken by the Agreement's signatory governments.

With respect to procedures to determine exportable surpluses of natural gas from Canada, the NEB announced in April 1986 its decision to employ a reserves-to-production formula subsequent to a review it had begun prior to the conclusion of the Agreement. In view of concerns expressed about the effect of this new procedure on the supply/demand equilibrium and market access, and in response to rapidly evolving market circumstances, the NEB indicated its intention in late October 1986 to conduct a further review, the results of which will be known in 1987. Two producing provinces, Alberta and British Columbia, also set in motion reviews of their respective surplus protection procedures.

In Canada, significant changes occurred to facilitate the move from regulated pricing to a more flexible, market-oriented pricing regime for interprovincial natural gas trade during the transition year provided in the Agreement. The federal and Alberta governments enacted legislative amendments enabling them to withdraw from the regulation of wholesale prices and other aspects of regulation. The NEB addressed and resolved questions concerning the duplication of demand charges and the availability of transportation service on the TransCanada PipeLines Limited system. Contract carriage on distributor systems under provincial jurisdiction was put into effect in Quebec, Ontario and Alberta. Direct sales and competitive marketing programs, negotiated between willing buyers and sellers, were made available. Pricing terms in existing long-term supply contracts between shippers and distributors were negotiated under netback arrangements. These pricing agreements for distributor sales, which came into effect on November 1, 1986, were the subject of regulatory proceedings by provincial authorities as the year came to a close.

Although considerable progress was achieved during this transition year, some concerns and additional issues have arisen which will require further consultation among governments and industry representatives in order to meet the spirit and intent of the Agreement.

During the year, domestic sales of natural gas decreased by slightly less than two percent. By the end of the transition year, some 30 per cent of natural gas volumes in interprovincial trade were moving under direct sales and competitive marketing programs at negotiated, market-responsive prices. On November 1, 1986, negotiated pricing arrangements also took effect for system sales, representing the balance of the interprovincial market. As a result of competitive circumstances, the average price of natural gas for domestic sales had decreased by year-end.

Petroleum

Overview of Operations

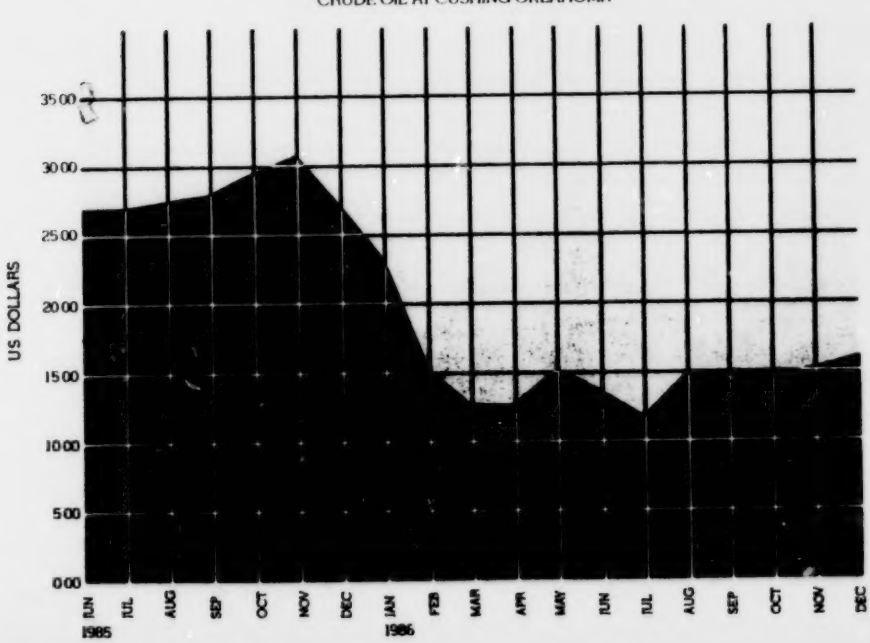
Under the authority of the Petroleum Marketing Act, the Commission, acting as agent, sells the Crown's royalty share of the province's crude oil production and its share of synthetic oil production from the Syncrude Canada Limited project in the public interest of Alberta. The Commission also markets crude oil on behalf of more than 200 producers under its mandate to provide marketing services on a contract basis. This additional crude oil production is purchased in accordance with normal business practices. These combined volumes make the Commission the largest crude oil marketer in Canada. The total production is gathered from producing locations in the field and transported by various pipelines to central locations within Alberta for subsequent delivery to customers in North America and offshore. By virtue of its direct involvement in this wide range of marketing activities, the Commission also provides analysis of industry pricing and marketing trends to the Government of Alberta.

Sales

Throughout the year, Alberta producers struggled to maintain revenues in the face of rapidly declining world oil prices (see Figure 1) and domestic pipeline deliverability problems. These factors created a particularly challenging marketing environment within which the Commission played a key role by expanding markets for Alberta crude oil, thereby reducing the amount of shut-in production in the province. These new markets included the United States Gulf Coast and Northwest regions and eastern Canada by tanker from Montreal.

During the year, the Commission also became a major shipper on the pipeline systems of Interprovincial Pipe Line Limited, Trans Mountain Pipe Line Company Ltd. and Rangeland Pipe Line Comany providing direct access to additional markets in eastern Canada and the United States.

FIGURE 1
MONTHLY AVERAGE NEW YORK MERCANTILE EXCHANGE SPOT PRICES WEST TEXAS INTERMEDIATE CRUDE OIL AT CUSHING OKLAHOMA



The Commission's sales of the Crown's royalty share of crude oil production totalled 9.0 million cubic metres (56.9 million barrels) as shown in Figure 2.

Sales of the Crown's royalty share of light and medium crude oil production fell from approximately 30 thousand cubic metres per day (190 thousand barrels per day) at the beginning of the year to 22 thousand cubic metres per day (135 thousand barrels per day) at year-end. This decrease was due mainly to higher levels of shut-in production and to the effect on the Crown's royalty share of production of lower prices and adjustments to the province's royalty system to provide assistance to the producing industry.

Sales of the Crown's royalty share of heavy crude oil and bitumen production totalled approximately 0.9 million cubic metres (5.5 million barrels) in 1986. A large portion of this production was sold to local purchasers.

Total revenue from all sales of crude oil was $1.68 billion.

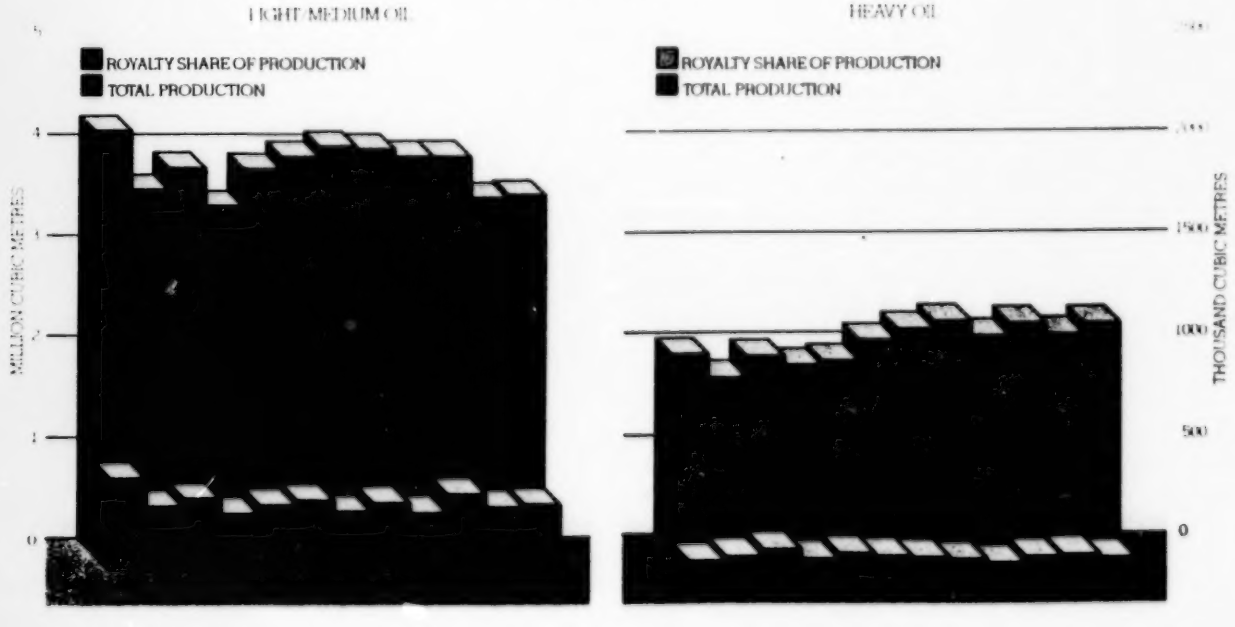
Pricing

Sales of conventional crude oil, adjusted for quality, netted an average field price of $121.30 per cubic metre ($19.28 per barrel), down 47 percent from price levels achieved over the last seven months of 1985 following the deregulation of crude oil.

Syncrude

The province has 16.74 percent equity participation in the Syncrude Canada Limited project and receives a 50 percent share of the project's deemed net profits in lieu of royalty. During the year, net profits accruing to the Crown from the project were taken as production in kind and marketed by the Commission along with the province's equity share of production. The total volume of Syncrude production sold by the Commission fell approximately 25 percent from 1985 levels to 1.3 million cubic metres (8.2 million barrels). Record high levels of production at the Syncrude project helped offset a significantly lower net profits share of production.

FIGURE 2
ROYALTY SHARE OF ALBERTA CONVENTIONAL CRUDE OIL PRODUCTION



Natural Gas

Overview of Operations
The Commission's functions and responsibilities pertaining to natural gas marketing changed significantly during the year due to the implementation of the October 31, 1985 Agreement on Natural Gas Markets and Prices (the Agreement). Prior to November 1, 1986, the Commission carried out duties related to regulated pricing, among which were:

- the determination of the Alberta Cost of Service,
- the purchase of natural gas and its subsequent resale,
- the administration of the Natural Gas Pricing Agreement Act Fund (Fund), the Natural Gas Pricing Agreement Act Market Development Fund (Market Development Fund) and the Ethane Feedstock Equalization Program, and
- the determination of natural gas sales eligible for exemption from price regulation, such as direct sales and competitive marketing programs.

Since November 1, 1986, the Commission's activities have included:

- the determination of costs, charges and revenues representing components of the price of natural gas at the request of producers and purchasers,
- the issuance of findings of producer support for netback pricing arrangements,
- the collection of take-or-pay levies and the administration of the Take-or-pay Costs Sharing Fund, and
- the collection and analysis of information on natural gas prices and markets for the purposes of verifying royalty payments by producers, monitoring progress under the Agreement and developing government policies.

In addition, the Commission began finalizing several matters associated with price regulation, such as auditing, verifying and resolving any outstanding problems associated with contribution to and claims upon the Fund and the Market Development Fund and with the determination of the Alberta Cost of Service. These activities are scheduled to be completed by October 31, 1987.

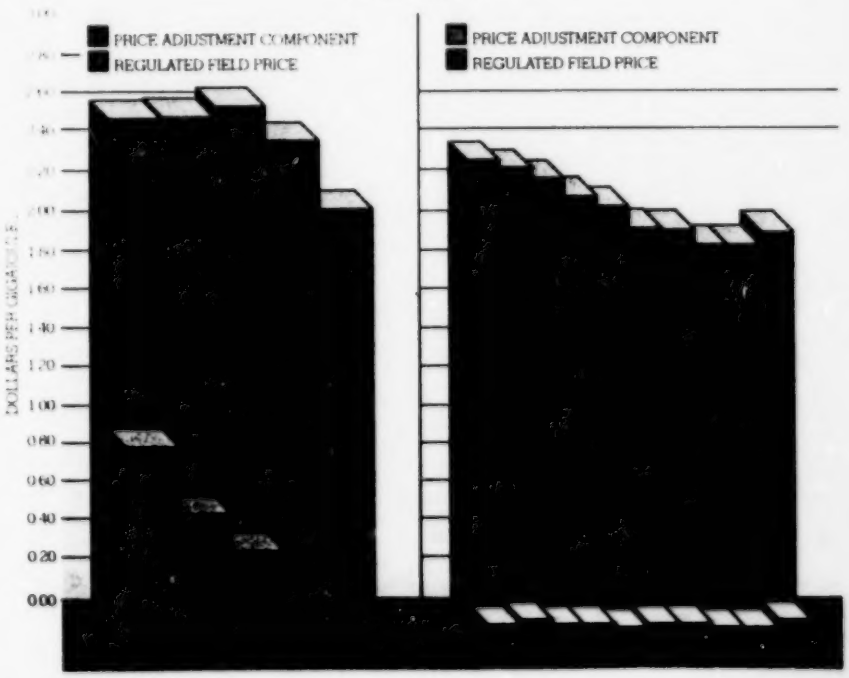
In undertaking these activities, the Commission operated under the authority of the Natural Gas Pricing Agreement Act, the Natural Gas Marketing Act and the Take-or-pay Costs Sharing Act.

Pricing
Under provisions of the Natural Gas Pricing Agreement Act in effect until October 31, 1986, the monthly regulated price for natural gas purchased by original buyers for removal from Alberta was the Alberta Border Price *less* Alberta Cost of Service *plus* Price Adjustment. During the transition year, competitive marketing programs, direct sales between producers and end-users and incremental sales to distributors were exempt from price regulation, provided the Commission determined that the qualifying conditions were in place.

Natural gas purchased for consumption within Alberta was priced at the lesser of the contract field price specified in a sales contract plus Price Adjustment *or* the Alberta Border Price less Alberta Cost of Service plus Price Adjustment.

Average regulated field prices are shown in Figure 3. As of November 1, 1986, field prices for natural gas have been determined by negotiation between buyers and sellers.

FIGURE 3
REGULATED FIELD PRICE
OF NATURAL GAS

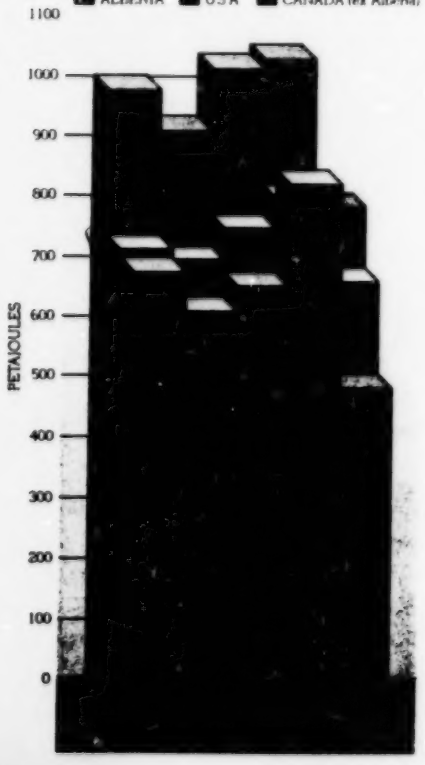


The Agreement also provided that natural gas exports, previously not allowed at prices less than the Toronto city Gate price, would be permitted as long as the prices paid by Canadians for similar types of service in the zone adjacent to the export point were lower. This was modified as of November 1, 1986 to a system of post facto monitoring.

Price Adjustment

Prior to November 1, 1986, all natural gas acquired by original buyers in Alberta was purchased by the Commission. Natural gas destined for the Canadian market was sold back to the original buyer at the purchase price, while natural gas destined for export markets was resold to the original buyer at the export price less transmission costs. The proceeds from these buy/sell transactions for export natural gas constituted the Fund from which payments under price adjustment, the Market Development Incentive Program and Transportation Assistance Program were made. The quantities and destinations of natural gas sold by the Commission are shown in Figure 4.

FIGURE 4
DESTINATION OF NATURAL GAS
SOLD BY THE COMMISSION



In each month prior to October 31, 1986, the Commission calculated a price adjustment based on proceeds available in the Fund and estimated quantities of natural gas produced for market. Alberta producers received a monthly price adjustment for all eligible deliveries or, in some circumstances, they made claims directly upon the Fund. Original buyers were reimbursed from the Fund for price adjustments paid to producers through the regulated field price.

During these ten months, the Commission purchased 1 904 petajoules (1,808.0 billion cubic feet) of natural gas for which it paid $4.1 billion and which it sold for $4.2 billion, resulting in proceeds to the Fund of $112 million. Total gas production for market was 2 070 petajoules (1,966.5 billion cubic feet), on which a price adjustment averaging $0.03 per gigajoule ($0.03 per million cubic feet) was paid from Fund proceeds.

The price adjustment, expressed in dollars per gigajoule, set by the Commission from January to the end of October, 1986 was as follows:

January	0.03	June	0.03
February	0.05	July	0.03
March	0.03	August	0.02
April	0.03	September	0.02
May	0.02	October	0.05

The weighted average price for natural gas exported to the United States was $3.38 per gigajoule ($3.56 per million cubic feet) for the ten months ended October 31. This compared to $4.05 per gigajoule ($4.26 per million cubic feet) for 1985.

Alberta Cost of Service
Until October 31, 1986, original buyers who removed natural gas from Alberta applied to the Commission each month for a determination of the Alberta Cost of Service for natural gas purchased in the month. The Alberta Cost of Service included costs and charges relating to the acquisition and transportation of natural gas from the point of purchase to the Alberta border. The monthly averages of Alberta costs of service over the last five years are shown in Figure 5.

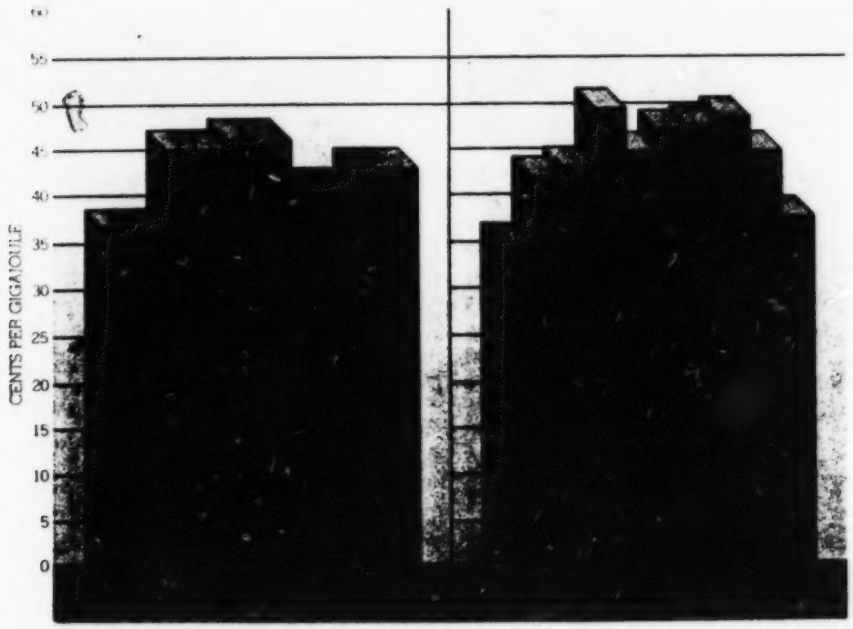
During the year, transportation costs represented 52 percent of the total Alberta Cost of Service, the costs of financing take-or-pay payments 35 percent, the Market Development Levy funding the Natural Gas Markets Incentive Plan two percent, and the original buyers' administration costs the remaining 11 percent.

The Commission, upon receiving an application or statement of objection from an original buyer or on its own initiative, made rulings on matters of principle and matters involving categories of costs and charges eligible for inclusion in the Alberta Cost of Service. Rulings on 11 applications and six statements of objection were issued in 1986. Rulings may be appealed to the Alberta Public Utilities Board.

Market Development Incentive Payments
In order to encourage the expansion of markets for Alberta-produced natural gas in provinces east of Alberta, the 1981 Memorandum of Agreement respecting Gas Pricing between the Government of Canada and the Government of Alberta provided for market development incentive payments to be made by the Commission from the Market Development Fund to the federal government. These payments were to be used to encourage the expansion of natural gas transmission and distribution facilities and for sales promotion programs. On April 1, 1985, the signatories agreed to advance the program's expiry date from January 31, 1987 to April 30, 1986 and to limit payments to no more than $160 million for the period February 1, 1985 to April 30, 1986. The entire amount was paid out by the Commission during this 15-month period. Payments during the life of the program totalled $302 million.

Under the terms of the October 1985 Agreement, the toll increase accorded TransCanada PipeLines Limited (TCPL) for the period from November 1, 1985 to October 31, 1986 was absorbed through an extension of the Market Development Incentive Program called the Transportation Assistance Program. Payments applicable to Alberta natural gas intended for domestic consumption outside Alberta totalled $97 million in 1986 to the end of October under this program extension. During the life of the program, $117 million was paid out by the Commission.

FIGURE 5
AVERAGE OF ALBERTA
COSTS OF SERVICE



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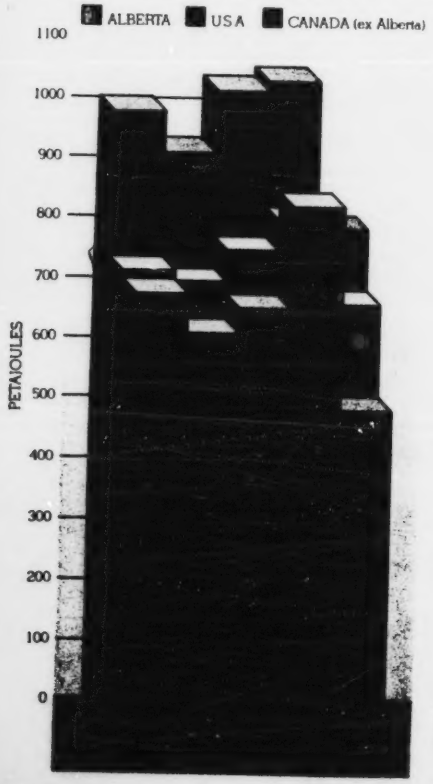

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FIGURE 5
AVERAGE OF ALBERTA
COSTS OF SERVICE

Natural Gas Markets Incentive Plan

The Natural Gas Markets Incentive Plan was in effect from May 1, 1984 to April 30, 1986 pursuant to the June 30, 1983 Agreement to Amend the Memorandum of Agreement of September 1, 1981 between the governments of Canada and Alberta. The Plan's purposes were to maintain and expand natural gas sales in provinces east of Alberta. Incentive payments were made by the Commission to natural gas distributors in Manitoba, Ontario and Quebec which, in turn, provided rebates to large industrial and commercial customers whose natural gas consumption exceeded previous levels. The Plan was amended under the terms of the October 1985 Agreement to render ineligible for payments those consumers taking advantage of direct sales and competitive marketing programs.

Payments under the Plan were funded by a Market Development Levy assessed on natural gas removed from Alberta and collected by way of an Alberta cost of service surcharge. Levies assessed in 1986 ranged from $0.04 per gigajoule ($0.04 per million cubic feet) in January to $0.02 per gigajoule ($0.02 per million cubic feet) in April. During 1986, $45 million was paid to distributors under the Plan. Payments during the life of the Plan totalled $101 million.

Take-or-pay Costs Sharing Fund

The National Energy Board (NEB), under the terms of the October 1985 Agreement, was requested to review the availability of transportation service on the TCPL system, taking into account the equitable and fair sharing of take-or-pay charges. In its May 1986 report, the NEB recommended the sharing of take-or-pay costs by Alberta non-system natural gas transported on the system and that sharing arrangements be administered by the Government of Alberta.

In response, the Government of Alberta enacted the Take-or-pay Costs Sharing Act. It provides for the sharing of TCPL's and Consolidated Natural Gas Limited's (Consolidated) take-or-pay financing costs commencing November 1, 1986 by way of a monthly levy on users of the TransCanada pipeline system whose shipping arrangements were entered into after October 31, 1985.

The Commission makes monthly determinations of levies to be applied to TCPL producers, Consolidated producers and to certain shippers on the Nova, An Alberta Corporation pipeline system. It also determines on a monthly basis the quantities of natural gas exempted from the levies. Revenues derived from the assessment of levies are channelled into the Take-or-pay Costs Sharing Fund, from which payments are made.

Regulatory Affairs

During the course of 1986, the Commission participated in and monitored several regulatory proceedings in Canada and the United States on behalf of the Government of Alberta. Issues raised in these proceedings had potential impact on the terms and conditions under which Alberta's oil and natural gas production is marketed. In both countries, regulatory activities had significant impact on the progress of natural gas deregulation.

Early in the year, the Commission participated in a hearing before the National Energy Board (NEB) dealing with the availability of transportation services for direct sales of natural gas on interprovincial pipeline systems. The Commission advocated that any overrecovery of demand charges resulting from the displacement of distributors sales by direct sales should be credited to the overall TransCanada PipeLines Limited (TCPL) cost of service and that all direct sales should bear a proportionate share of the carrying costs of TCPL's take-or-pay obligations. In its decision, the NEB resolved the issue of duplicate demand charges by refunding overrecoveries already collected and by allowing distributors to reduce their contract demand obligations to operational demand levels. Citing a lack of legislative authority to deal with the issue of the equitable sharing of take-or-pay carrying costs, the NEB also recommended that the Government of Alberta levy a charge on all shippers of Alberta natural gas on the TCPL system to effect a sharing of these costs.

The Commission also took an active role in the NEB proceeding respecting the setting of tolls for Westcoast Transmission Company Limited (Westcoast) because of its concern that the cost allocation methods proposed by Westcoast would reduce netbacks to Alberta producers shipping natural gas on the Westcoast system to export markets. The NEB decision concurred with the Commission's position that the allocation of fixed costs within Zone 3 (the zone in which Alberta natural gas moves) should incorporate a distance factor and that the implementation of an interruptible displacement toll for the export market would be unduly discriminatory.

In the 1986 tolls application by TransQuebec & Maritimes Inc. to the NEB, the Commission participated in pre-hearing negotiations which resulted in settling, outside the hearing process, all issues with the exception of the appropriate rate of return on common equity. This outstanding issue was decided by the NEB to the Commission's satisfaction.

In September 1986, the NEB initiated what was to become a lengthy proceeding to determine TCPL's 1986/87 tolls. The Commission submitted that it was imprudent of TCPL to request a large toll increase in light of the downturn prevailing in the producing industry. The Commission took issue with increases in operating and administrative costs, requests for deferral accounts, the recovery of revenue deficiencies and a proposed increase in equity capitalization. These and other proposals would result in increased costs to TCPL ratepayers, thereby reducing netbacks to Alberta producers. At year-end, the hearing had not yet concluded.

The Commission also actively participated in an Interprovincial Pipe Line Limited (IPL) tolls hearing before the NEB. The Commission advocated a decrease in IPL's proposed rate of return and proposed a change in methodology for calculating medium and heavy crude oil surcharges to reflect the additional costs of transporting such crudes. The Commission argued in favour of separate tariff treatment on a user-pay basis for the proposed conversion of the Sarnia/Montreal portion of the pipeline to include natural gas liquids service and of a small line in Ontario to propane service on the grounds that these projects would not generally benefit all crude oil shippers. At year-end, the NEB's decision had yet to be released.

The Commission unsuccessfully opposed TCPL's proposal to amortize foreign exchange and premium redemption costs associated with the refinancing of two foreign currency notes.

Several matters related to TCPL's application to add to its facilities to deliver natural gas to Boundary Gas Inc. and Tennessee Gas Pipeline Limited in the United States Northeast at a cost of $10.2 million were questioned by the Commission. The application was approved, subject to several conditions, in a manner which satisfied the Commission's concerns.

On the grounds that the necessary investments were of low risk to IPL and were required to provide additional pipeline capacity to alleviate shut-in crude oil problems in Alberta, the Commission filed a letter of comment supporting an application for an expansion of the IPL system. The application was approved.

The NEB, after comments by the Commission that a rate of return on equity requested by Alberta Natural Gas Company was too high, approved a rate at a significantly lower level.

At the provincial level, the Commission monitored proceedings before the Ontario Energy Board and the Manitoba Public Utilities Board in respect of the availability of contract carriage on distributor systems. Other hearings were monitored which dealt with changes in rates resulting from the negotiation of natural gas pricing agreements between Western Gas Marketing Limited and various distributors, pursuant to the October 31, 1985 Agreement on Natural Gas Markets and Prices.

In the United States, the Commission filed a submission with the Federal Energy Regulatory Commission (FERC) respecting a settlement agreement under FERC Order 436 proposed by Northern Natural Gas Company and was unsuccessful in arguing that the proposed postage stamp tariff should be rejected on the grounds that it discriminated unduly against Canadian natural gas to the benefit of domestic production.

The Commission filed interventions for monitoring purposes in various other proceedings before the FERC to identify potential restrictions to or opportunities for the export of Alberta natural gas to the United States. Of special interest were applications concerning the delivery of natural gas to the enhanced oil recovery market in California and several applications by the proponents of various facilities for the import of Canadian natural gas to serve markets in the United States Northeast. All applications for open access transportation under FERC Order 436 were monitored to determine their impact on export sales.

The Commission also registered its objection with the Economic Regulatory Administration (ERA) of the United States Department of Energy to a proposal advanced by United States producers designed to limit import authorizations to those sales for which transportation arrangements were with open access pipelines under FERC Order 436. At year-end, the ERA had not yet responded to the proposal.

The California Public Utilities Commission's (CPUC) proceeding examining new proposals for long-term rate design in the State of California, which is the largest export market for Alberta natural gas, was also actively monitored. The rate design ultimately approved by the CPUC will affect opportunities for Alberta natural gas sales, especially through the methods approved for opening up the state's transportation system.

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Alberta Petroleum Marketing Commission as at December 31, 1986 and the statements of revenue and expenditure for the Operating Fund and the Ethane Feedstock Price Equalization Program and the statement of operations for the Petroleum Marketing Fund for the year then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Commission as at December 31, 1986 and the results of its operations for the year then ended in accordance with the disclosed basis of accounting, considered appropriate in the circumstances, as described in Note 2 to the financial statements applied on a basis consistent with that of the preceding year.

Donald D. Salmon
C.A.
Auditor General

Edmonton, Alberta
April 24, 1987

Alberta PETROLEUM MARKETING COMMISSION

BALANCE SHEET

As At December 31, 1986

	1986	1985
ASSETS		
OPERATING FUND		
Current		
Cash and short-term deposits	**$ 8,348,671**	$ 7,199,478
Accounts receivable	**667,072**	794,717
	9,015,743	7,994,195
Furniture, equipment and leasehold improvements, at cost (Note 4)	**3,565,534**	3,433,587
	12,581,277	11,427,782
PETROLEUM MARKETING FUND		
Current		
Cash and short-term deposits	**38,383,783**	62,607,670
Accounts receivable	**114,287,420**	359,850,397
	152,671,203	422,458,067
ETHANE FEEDSTOCK PRICE EQUALIZATION PROGRAM (Note 5)		
Current		
Cash and short-term deposits	**—**	4,751,645
Accounts receivable — sales	**—**	15,077,454
Receivable from the Province of Alberta	**—**	10,225,752
	—	30,054,851
	$165,252,480	$463,940,700

The accompanying notes are part of these financial statements.

	1986	1985
LIABILITIES		
OPERATING FUND		
Current		
Accounts payable	**$ 439,048**	$ 1,855,419
Payable to the Province of Alberta	**6,667,445**	4,483,526
Deferred contributions (Note 2)	**1,909,250**	1,655,250
	9,015,743	7,994,195
Equity in fixed assets (Note 2)	**3,565,534**	3,433,587
	12,581,277	11,427,782
PETROLEUM MARKETING FUND		
Current		
Accounts payable	**54,430,571**	113,948,870
Crown royalty payable	**98,240,632**	308,509,197
	152,671,203	422,458,067
ETHANE FEEDSTOCK PRICE EQUALIZATION PROGRAM		
Current		
Accounts payable — purchases	**—**	20,054,851
Accountable advance from the Province of Alberta	**—**	10,000,000
	—	30,054,851
	$165,252,480	463,940,700

Alberta PETROLEUM MARKETING COMMISSION

STATEMENT OF REVENUE AND EXPENDITURE
OPERATING FUND

For The Year Ended December 31, 1986

	1986	1985
Revenue		
Interest	**$3,423,404**	$3,085,343
Crude oil marketing fees (Note 6)	**4,035,208**	2,859,622
	7,458,612	5,944,965
Expenditure		
Salaries and employee benefits	**4,909,730**	4,356,489
Rental of premises (Note 8)	**1,159,876**	1,057,024
Technical studies	**500,373**	536,013
Travel	**243,843**	215,135
Computer services	**230,044**	226,192
Furniture and equipment	**147,045**	999,842
Printing and office supplies	**128,233**	119,831
Publications and periodicals	**68,050**	52,240
Personnel recruitment	**59,054**	131,622
Rental of office equipment	**57,613**	49,825
Telephone	**35,609**	28,799
Leasehold improvements	**34,416**	170,452
Postage and freight	**27,663**	39,649
Building and equipment maintenance	**15,320**	11,201
Insurance	**6,834**	3,447
Bank charges	**6,720**	–
Advertising	**5,802**	22,081
Miscellaneous	**13,193**	12,120
	7,649,418	8,031,962
Excess of expenditure over revenue	**190,806**	2,086,997
Contributions from the Province of Alberta	**190,806**	2,086,997
	$ –	$ –

Alberta PETROLEUM MARKETING COMMISSION

STATEMENT OF OPERATIONS
PETROLEUM MARKETING FUND

For The Year Ended December 31, 1986

	1986	1985
Revenue (Note 6)		
Sale of crude oil	**$1,680,003,230**	$7,319,676,307
New oil reference price supplement (Note 7)	**286,199**	864,684,166
Special old oil price supplement (Note 7)	**—**	755,249
	1,680,289,429	8,185,115,722
Expenditure (Note 6)		
Transportation	**61,694,901**	108,694,530
Purchases		
Contract and other	**540,012,230**	1,609,162,619
Crown lessees	**—**	3,336,912,090
	601,707,131	5,054,769,239
Royalty share remitted to the Province of Alberta	**$1,078,582,298**	$3,130,346,483

Alberta PETROLEUM MARKETING COMMISSION

STATEMENT OF REVENUE AND EXPENDITURE
ETHANE FEEDSTOCK PRICE EQUALIZATION PROGRAM

For The Year Ended December 31, 1986

	1986	1985
Revenue		
Sale of natural gas	**$ 81,002,488**	$188,200,606
Expenditure		
Purchases of natural gas	**108,390,129**	240,017,503
Excess of expenditure over revenue	**27,387,641**	51,816,897
Contributions from the Province of Alberta	**27,387,641**	51,816,897
	$ —	$ —

Alberta PETROLEUM MARKETING COMMISSION

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1986

Note 1 Authority

The Alberta Petroleum Marketing Commission operates under the authority of the Petroleum Marketing Act, Chapter P-5, Revised Statutes of Alberta 1980, as amended, and the Natural Gas Marketing Act, Chapter N-2.8, Statutes of Alberta 1986, which was proclaimed in force on October 30, 1986.

These financial statements disclose financial transactions undertaken by the Commission on behalf of the Minister of Energy, related to the Ethane Feedstock Price Equalization Program (Note 5). The principal elements of the Program were contained in two agreements to which the Crown, but not the Commission, was a party. The Commission performed administrative functions under the agreements on behalf of the Crown. There appears to be no express authority in the Alberta statutes for the Commission to have performed its administrative functions under the agreements, and the Commission relied on the provisions of the agreements as its authority for that purpose.

Note 2 Significant Accounting Policies

General

These financial statements have been prepared in accordance with generally accepted accounting principles, with the following exceptions:

a) Purchases of furniture, equipment and leasehold improvements are charged to operating fund expenditure in the year of acquisition. However, the balance sheet states the cumulative amount of such expenditures in respect of all fixed assets presently owned with the offsetting credit to equity in fixed assets.

b) Assets and liabilities in foreign currencies have been translated into Canadian dollars at forward exchange contract rates or, where not covered by forward exchange contracts, at the rate of exchange in effect at the balance sheet date.

Deferred Contributions

The portion of contributions received from the Province of Alberta to cover operating costs for the period January 1, 1987 to March 31, 1987 has been deferred. Contributions by the Province are based on a yearly budget for the period April 1 to March 31.

Operating Fund Expenditure

The Natural Gas Pricing Agreement Act Fund and Natural Gas Pricing Agreement Market Development Fund were administered by the Commission pursuant to the Natural Gas Pricing Agreement Act. The Take-or-pay Costs Sharing Fund, which came into effect November 1, 1986, is administered pursuant to the Take-or-pay Costs Sharing Act. The expenditure related to the administration of these Funds is reflected in the Statement of Revenue and Expenditure – Operating Fund.

Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered to be adequate.

Note 3 Change in Reporting Practise

Syncrude Marketing Activities

The Commission's activities related to the marketing of synthetic crude oil from the Syncrude Project are now recorded in the Balance Sheet and Statement of Operations of the Petroleum Marketing Fund. Revenue for 1986 was $162,802,526 (1985 $386,362,458).

Note 4 Furniture, Equipment and Leasehold Improvements

Changes in furniture, equipment and leasehold improvements were as follows

	Balance December 31, 1985	Additions	Disposals	Balance December 31, 1986
Furniture and equipment	$ 2,646,956	$ 154,284	$ 56,753	$ 2,744,487
Leasehold improvements	786,631	34,416	–	821,047
	$ 3,433,587	$ 188,700	$ 56,753	$ 3,565,534

Note 5 Ethane Feedstock Price Equalization Program

The Commission, on behalf of the Province of Alberta, conducted buy-sell transactions to ensure that producers of ethane by-products had access to natural gas feedstock at a price equal to the average price for intra-Alberta industrial gas. This program commenced in April, 1985 and applied to transactions from November 1, 1984 to June 30, 1986, at which time the program was terminated. Funding for this program was provided by the Province of Alberta, Department of Energy.

Note 6 Deregulation

Pursuant to the Energy Pricing and Taxation Understanding entered into by the governments of Alberta and Canada on March 27, 1985, the Commission's activities changed effective June 1, 1985. Although still responsible for marketing Crown royalty oil, the Commission ceased to act as the exclusive agent for marketing of the Crown lessees' share and became a competitor with other buyers and sellers of petroleum.

Revenue and Expenditure - Operating Fund

Crude Oil Marketing Fees

The 1985 comparative figure reflects fees earned as agent of Crown Lessees for the seven month period following deregulation.

Operations - Petroleum Marketing Fund

The 1985 comparative figures in the Statement of Operations of the Petroleum Marketing Fund reflect transactions related to deliveries prior to and under deregulation as follows:

	May 1985 and Prior Deliveries	June 1985 to December 1985 Deliveries	Total
Revenue			
Sales	$ 4,796,261,530	$ 2,523,414,777	$ 7,319,676,307
NORP supplement	864,684,166	–	864,684,166
SOOP supplement	755,249	–	755,249
	5,661,700,945	2,523,414,777	8,185,115,722
Expenditure			
Transportation	74,810,146	33,884,384	108,694,530
Purchases			
Contract and other	890,213,704	718,948,915	1,609,162,619
Crown lessees	3,336,912,090	–	3,336,912,090
	4,301,935,940	752,833,299	5,054,769,239
Royalty share remitted to the Province of Alberta	$ 1,359,765,005	$ 1,770,581,478	$ 3,130,346,483

Note 7 New Oil Reference/Special Old Oil Price Supplements

New Oil Reference Price Supplement Payments

Effective January 1, 1982, pursuant to the Canada-Alberta agreement on energy pricing dated September 1, 1981, oil discovered after December 31, 1980 became eligible for the New Oil Reference Price (NORP). NORP supplement payments were received from the federal government for the difference between the established NORP price and the field price for conventional old oil. The NORP supplement payments were extended to cover pentanes plus and bitumen effective April 1, 1982. With the advent of the Energy Pricing and Taxation Understanding, the NORP program was discontinued May 31, 1985 and crude oil prices deregulated. NORP supplements received during the current year are adjustments relating to previous years' deliveries.

Special Old Oil Price Supplement Payments

Effective July 1, 1982, pursuant to The National Energy Program Update of May 1982, oil discovered from April 1, 1974 to December 31, 1980 became eligible for the Special Old Oil Price (SOOP). SOOP supplement payments were received from the federal government for the difference between the established SOOP price and the field price for conventional old oil. This category became eligible for NORP prices, effective July 1, 1983. SOOP supplements received during 1985 were adjustments relating to the period ended June 30, 1983.

Note 8 Commitment

Effective December 1, 1981, the Commission signed a fifteen year lease for office accommodation at a minimum annual rental of $692,360 plus occupancy costs.

Note 9 Comparative Figures

The 1985 figures have been reclassified where necessary to conform to the 1986 presentation.

Note 10 Approval of Financial Statements

These financial statements were approved by the Commission.

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Natural Gas Pricing Agreement Act Fund as at December 31, 1986 and the statement of revenue, expenditure and fund balance for the year then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Fund as at December 31, 1986 and the results of its operations for the year then ended in accordance with generally accepted accounting principles applied on a basis consistent with that of the preceding year.

Donald D. Salmon

C.A.
Auditor General

Edmonton, Alberta
April 24, 1987

NATURAL GAS PRICING AGREEMENT ACT FUND

BALANCE SHEET

As At December 31, 1986

	1986	1985
ASSETS		
Current		
Cash and short-term deposits	**$14,354,890**	$105,469,665
Accounts receivable	**202,950**	49,313,853
	$14,557,840	$154,783,518
LIABILITIES AND FUND BALANCE		
Current		
Price adjustments payable	**$ 27,821**	$ 14,569,360
Market development incentive payable	**—**	58,414,158
Export differential refund payable	**3,166,246**	—
	3,194,067	72,983,518
Reserve for market development incentive payments (Note 4)	**—**	81,800,000
Fund balance (Note 5)	**11,363,773**	—
	$14,557,840	$154,783,518

The accompanying notes are part of these financial statements.

NATURAL GAS PRICING AGREEMENT ACT FUND

STATEMENT OF REVENUE, EXPENDITURE AND FUND BALANCE

For The Year Ended December 31, 1986

	1986	1985
Revenue		
Export differential		
Natural gas sales	**$4,178,143,188**	$6,737,395,701
Cost of gas sold	**4,065,981,105**	6,039,098,906
	112,162,083	698,296,795
Interest	**7,374,379**	4,564,890
	119,536,462	702,861,685
Expenditure		
Price adjustments	**60,309,063**	457,787,614
Market development incentive payments (Note 3)	**129,663,626**	157,946,959
Transfer to Natural Gas Pricing Agreement Market Development Fund (Note 3)	**–**	5,327,112
	189,972,689	621,061,685
Excess (deficiency) of revenue over expenditure	**(70,436,227)**	81,800,000
Transfer from (to) reserve for market development incentive payments	**81,800,000**	(81,800,000)
Fund balance	**$ 11,363,773**	$ –

NATURAL GAS PRICING AGREEMENT ACT FUND

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1986

Note 1 Authority

The Natural Gas Pricing Agreement Act Fund was established by the Natural Gas Pricing Agreement Act, Chapter N-4, Revised Statutes of Alberta 1980, as amended.

Pursuant to the Western Accord and the Canada-Alberta agreement on gas pricing, the Commission ceased the purchasing and selling of natural gas and the distribution of export differential with respect to any gas delivered after October 31, 1986.

Note 2 Significant Accounting Policies

Administration Costs

In accordance with the Natural Gas Pricing Agreement Act, the Fund is administered by the Alberta Petroleum Marketing Commission. Costs of administration are reflected in the Commission's Statement of Revenue and Expenditure — Operating Fund.

Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered to be adequate.

Note 3 Market Development Incentive Payments

In accordance with the Canada-Alberta agreement on gas pricing of November 1981 as amended, payments were made to the Government of Canada for the period November 1, 1981 to April 30, 1986 to facilitate the expansion of markets for Alberta-produced gas in provinces east of Alberta. Amendments to the agreement required that additional amounts be paid to the Government of Canada for the purpose of making transportation assistance payments. These additional payments served to maintain tolls charged by TransCanada PipeLines Limited for the period November 1, 1985 to October 31, 1986 at 1984-85 levels.

Under the terms of the agreement, payments to the Government of Canada were limited to $75,000,000 for the year ended April 30, 1985, and to $160,000,000 for the 15 month period ended April 30, 1986. However, the Natural Gas Pricing Agreement Act provided that any amount in excess of the limitations, which would otherwise have been paid to the Government of Canada, was available to be transferred to the Natural Gas Pricing Agreement Market Development Fund. In 1985, an amount of $5,327,112 was transferred in accordance with this provision.

Market development incentive payments were as follows:

	1986	1985
Transportation assistance	**$ 96,697,034**	$ 20,253,522
Expansion of markets	**32,966,592**	137,693,437
	$129,663,626	$157,946,959

Note 4 Reserve for Market Development Incentive Payments

The reserve for market development incentive payments represented an appropriation of funds to meet future obligations under the market development incentive payment programs outlined in Note 3 above.

Note 5 Fund Balance

Upon the completion of audits, any remaining Fund balance will be distributed based on October, 1986 deliveries.

Note 6 Comparative Figures

Inasmuch as the Fund ceased collection and distribution of export differential with respect to gas delivered after October 31, 1986, current year figures include only ten delivery months.

Note 7 Approval of Financial Statements

These financial statements were approved by the Commission.

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the statement of receipts, payments and fund balance of the Natural Gas Pricing Agreement Market Development Fund for the year ended December 31, 1986. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, this financial statement presents fairly the balance of the Fund as at December 31, 1986 and the receipts collected and payments made for the year then ended in accordance with the disclosed basis of accounting, considered appropriate in the circumstances, as described in Note 2 to the financial statement applied on a basis consistent with that of the preceding year.

Donald D. Salmon

C.A.
Auditor General

Edmonton, Alberta
April 24, 1987

NATURAL GAS PRICING AGREEMENT MARKET DEVELOPMENT FUND

STATEMENT OF RECEIPTS, PAYMENTS AND FUND BALANCE

For The Year Ended December 31, 1986

	1986	1985
Receipts		
Market development levies	**$ 28,067,585**	$57,857,086
Transfer from Natural Gas Pricing Agreement Act Fund (Note 3)	**–**	5,327,112
Interest	**1,119,087**	1,412,683
	29,186,672	64,596,881
Payments		
Retention incentives	**24,315,823**	28,810,437
Development incentives	**21,157,829**	24,510,180
	45,473,652	53,320,617
Excess (deficiency) of receipts over payments	**(16,286,980)**	11,276,264
Fund balance, beginning of year	**18,416,976**	7,140,712
Fund balance, end of year (Note 4)	**$ 2,129,996**	$18,416,976

The accompanying notes are part of this financial statement.

NATURAL GAS PRICING AGREEMENT MARKET DEVELOPMENT FUND

NOTES TO THE FINANCIAL STATEMENT

December 31, 1986

Note 1 Authority

The Natural Gas Pricing Agreement Market Development Fund was established by the Natural Gas Pricing Agreement Act, Chapter N-4, Revised Statutes of Alberta 1980, as amended.

Pursuant to the Western Accord, the Natural Gas Markets Incentive Plan, which provided incentives for retention and development of natural gas markets in provinces east of Alberta, ended April 30, 1986.

Note 2 Significant Accounting Policies

General

The Fund's financial statement, since inception, has been prepared on a cash basis. Upon the completion of audits of the contributors, the remaining Fund balance will be refunded thereto.

Reliance on Distributor Submissions

In accordance with the Natural Gas Pricing Agreement Act, the Commission entered into agreements with natural gas distributors in Manitoba, Ontario and Quebec for the purpose of providing incentives for the retention and development of natural gas markets by those distributors. The incentives were provided in respect of gas delivered in a plan year in excess of established base quantities.

The agreements provided for retention and development incentive payments by the Commission to distributors, who in turn passed these payments on to their customers, based on natural gas consumption at eligible facilities. In accordance with these agreements, the Commission relied on certified submissions received from distributors as the basis for payments made from the Fund. Further, the agreements required that a compliance report be prepared by the distributors' auditors and be provided to the Commission within six months following the end of each plan year.

Administration Costs

In accordance with the Natural Gas Pricing Agreement Act, the Fund is administered by the Alberta Petroleum Marketing Commission. Costs of administration are reflected in the Commission's Statement of Revenue and Expenditure — Operating Fund.

Note 3 Transfer from Natural Gas Pricing Agreement Act Fund

Under the terms of the Natural Gas Pricing Agreement Act, when a limitation on the amount of market development incentive payments was in effect, any amount in excess of the limitation which would otherwise have been paid to the Government of Canada, was available to be transferred from the Natural Gas Pricing Agreement Act Fund to the Natural Gas Pricing Agreement Market Development Fund. The amount of $5,327,112 represents the transfer for the year ended April 30, 1985.

Note 4 Fund Balance

The Fund balance is represented by cash and short-term deposits.

Note 5 Comparative Figures

Inasmuch as the plan ended April 30, 1986, current year figures include only four delivery months.

Note 6 Approval of Financial Statement

This financial statement was approved by the Commission.

ALBERTA LEGISLATURE

OFFICE OF THE AUDITOR GENERAL

AUDITOR'S REPORT

To the Members of the
Alberta Petroleum Marketing Commission

I have examined the balance sheet of the Take-or-pay Costs Sharing Fund as at December 31, 1986 and the statement of revenue and expenditure for the period then ended. My examination was made in accordance with generally accepted auditing standards, and accordingly included such tests and other procedures as I considered necessary in the circumstances.

In my opinion, these financial statements present fairly the financial position of the Fund as at December 31, 1986 and the results of its operations for the period then ended in accordance with generally accepted accounting principles.

Donald D. Salmon
C.A.
Auditor General

Edmonton, Alberta
May 6, 1987

TAKE-OR-PAY COSTS SHARING FUND

BALANCE SHEET

As At December 31, 1986

	1986
ASSETS	
Current	
Cash	$ 515,178
Accounts receivable	18,551,379
	$19,066,557
LIABILITIES	
Current	
Accounts payable	$ 6,481,386
Deferred revenue (Note 3)	12,585,171
	$19,066,557

The accompanying notes are part of these financial statements.

TAKE-OR-PAY COSTS SHARING FUND

STATEMENT OF REVENUE AND EXPENDITURE

For The Two Months Ended December 31, 1986

	1986
Revenue	
Take-or-pay levies	$27,210,815
Interest	861
	27,211,676
Expenditure	
Take-or-pay costs	27,211,676
Excess of revenue over expenditure	$ –

TAKE-OR-PAY COSTS SHARING FUND

NOTES TO THE FINANCIAL STATEMENTS

December 31, 1986

Note 1 Authority

The Take-or-pay Costs Sharing Fund was established by the Take-or-pay Costs Sharing Act, Chapter T-0.1, Statutes of Alberta 1986, and came into operation November 1, 1986.

Note 2 Significant Accounting Policies

Administration Costs

In accordance with the Take-or-pay Costs Sharing Act, the Fund is administered by the Alberta Petroleum Marketing Commission. Costs of administration are reflected in the Commission's Statement of Revenue and Expenditure – Operating Fund.

Changes in Financial Position

A statement of changes in financial position is not provided as disclosure in these financial statements is considered to be adequate.

Note 3 Deferred Revenue

The deferred revenue represents the portion of December, 1986 levies which will be used to pay future take-or-pay costs.

Note 4 Comparative Figures

Inasmuch as this is the first reporting period of the Fund, no comparative figures have been provided.

Note 5 Approval of Financial Statements

These financial statements were approved by the Commission.

COMMISSION DIRECTORY

(as at date of publication)

COMMISSION

Dale A. Lucas
Chairman

David L. Willis
Vice-Chairman

James E. MacKenzie
Member

GENERAL COUNSEL AND SECRETARY

Sheila F. McAllister

MANAGER, HUMAN RESOURCES

Orest L. Zwarich

MANAGER, SPECIAL PROJECTS

Céline Bélanger

FINANCE AND ADMINISTRATION DIVISION

Garth K. Palmer
Managing Director

T.N. Ritchie Fons
Comptroller

William G. Henderson
Manager, Financial Accounting - Petroleum

Brian R. Zapfe
Manager, Financial Accounting - Natural Gas & Payroll

CRUDE OIL DIVISION

Gordon R. Scott
Managing Director

Gary E. Baerg
Manager, Crude Oil Supply

Gerry H. Bietz
Manager, Crude Oil Sales

Robert F. McDonald
Manager, Crude Oil Pricing & Planning

Donald M. Olineck
Manager, Crude Oil Supply Accounting

NATURAL GAS AND MARKET ANALYSIS DIVISION

Robert H. Cook
Managing Director

Vernon M. Thomas
General Manager, Natural Gas

Edwin K. Adams
Auditor

William A. McKain
Manager, Operations

Robert McLean
Manager, Planning

Patrick C. Tsuen
Manager, Gas Markets

INFORMATION SERVICES DIVISION

Richard W. Tovell
Managing Director

Sam Leung
Manager, Computer Services

Tony Williams
Manager, Systems